UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region8

Ref: 8WD-SDU

SENT VIA EMAIL
DIGITAL READ RECEIPT REQUESTED

Michelle Yalung, Senior Regulatory Analyst
Michelle.Yalung@meritenergy.com

Re: Draft Permit - WY21098-07393, Tribal C-13

Dear Ms. Yalung:

Enclosed is a copy of the draft U.S. Environmental Protection Agency Region 8 Underground Injection Control (UIC) permit (Permit) for the above referenced well or project area. Also enclosed are copies of the statement of basis for the proposed action and the public notice provided on EPA's website at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy.

EPA regulations and procedures for issuing UIC permit decisions are found in Title 40 of the Code of Federal Regulations (40 CFR) part 124. These regulations and procedures require a public notice and the opportunity for the public to comment on this proposed Permit decision. The public comment period will run for at least 30 days and a courtesy announcement of the comment period, also enclosed, will be published in the following newspapers(s):

Riverton Ranger
Casper Star-Tribune

A final decision will not be made until after the close of the comment period. All relevant comments will be taken into consideration. If any substantial comments are received, the effective date of the final Permit will be delayed for an additional 30 days, as required by 40 CFR § 124.15(b), to allow for any potential appeal of the final Permit decision.

If you have any questions or comments about the above action, please contact Christopher Brown at (303) 312-6669 or Brown.Christopher.T@epa.gov.

Sincerely,

7/21/2021

X Lisa Kahn

Signed by: LISA KAHN
Lisa Kahn, Acting Chief
Safe Drinking Water Branch

Enclosures

cc: Jordan Dresser, Chairman, jordan.dresser@northernarapaho.com
Northern Arapahoe Business Council

John St. Clair, Chairman, jstclair@easternshoshone.org
Eastern Shoshone Business Council

Gordan Zane, Fluid Minerals Branch Chief, zane.gordon@bia.gov
U.S. Department of Interior, Bureau of Indian Affairs

John Elliott, Manager, Lander Field Office, j75ellio@blm.gov
U.S. Department of Interior, Bureau of Land Management

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT PERMIT

WY21098-07393

Class II Salt Water Disposal Well

Tribal C-13
Fremont County, Wyoming

Issued To

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

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PART I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this permit (Permit),

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

hereinafter referred to as the "Permittee," is authorized to operate the following Class II well:

Tribal C-13
320' FEL & 994' FSL, Section 30, Township 4N, Range 1W
Fremont County, Wyoming
49-013-06464

This Permit is based on representations made by the applicant and on other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

Where a state or tribe is not authorized to administer the UIC program under the SDWA, EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. Regulations specific to Indian country injection wells in Wyoming are found at 40 CFR § 147.2553.

The Permittee is authorized to engage in underground injection in accordance with the conditions of this Permit. Any underground injection activity not authorized by this Permit or by rule is prohibited.

Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the SDWA or any other law governing protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

This Permit is issued for the operating life of the facility or until it expires under the terms of the Permit, unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41, and shall be reviewed at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

Issue Date: ____________________ Effective Date ____________________

DRAFT

____

Lisa Kahn, Acting Chief*
Safe Drinking Water Branch

* Throughout this Permit the term "Director" refers to the Safe Drinking Water Branch Chief or the Water Enforcement Branch Chief.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing and packer.

EPA-approved well construction is incorporated into this Permit as APPENDIX A. Changes to the approved construction must be approved through permit modification by the Director, prior to being physically incorporated.

1. Casing and Cement

The well shall be cased and cemented to prevent the movement of fluids into or between USDWs and shall be in accordance with 40 CFR § 146.22. Remedial construction measures may be required if the well is unable to demonstrate mechanical integrity.

2. Injection Tubing and Packer

Injection tubing is required and shall be run and set with a packer. The packer setting depth may be changed, provided the well construction requirements in APPENDIX A are met and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices

The Permittee shall install and maintain in good operating condition:

(a) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead;

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the MAIP described in Part II, Section B.4:

  (i) on the injection tubing string(s);

  (ii) on the tubing-casing annulus (TCA); and

  (iii) on the surface casing-production casing (bradenhead) annulus;

(c) a sampling port such that samples shall be collected at a location that ensures they are representative of the injected fluid; and

(d) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

4. Pre-Injection Requirements

Pre-injection requirements prior to receiving authorization to inject are found in APPENDIX B. Specifically, authorization for injection as a salt water disposal (SWD) well will not be approved until the corrective action(s) required in APPENDIX F have been completed or an on-going monitoring plan has been approved under APPENDIX F.

In addition, authorization for injection as a SWD well will not be approved until a plan describing how fluids intended for disposal will be segregated from fluids injected for enhanced oil recovery by other Class II wells connected to the C-3 Battery has been submitted for EPA review, comment and approval as described in the Appendix C operating requirements.

Section B. WELL OPERATION

1. Outermost Casing Injection Prohibition

Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. Injection Zone and Fluid Movement

Injection zone means "a geological formation, group of formations, or part of a formation receiving fluids through a well."

Injection and perforations are permitted only within the approved injection zone specified in APPENDIX C. Injected fluids shall remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee shall notify the Director within twenty-four (24) hours and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

Additional individual injection perforations may be added, provided that they remain within the approved injection zone(s), fracture gradient data submitted is representative of the portion of the injection zone to be perforated, and the Permittee provides notice to the Director in accordance with Part II, Section B.8 for workovers. The Permittee shall also follow the requirements found in Part II Section B.4 *Injection Pressure Limitation* that may result in a change to the permitted MAIP.

3. Injection Pressure Limitation

(a) Injection pressure at the wellhead shall not initiate new fractures or propagate existing fractures in the confining zone. In no case shall injection pressure cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or other well tests approved by EPA, injection pressure shall not exceed the MAIP. The MAIP, as measured at the surface, shall equal the formation fracture pressure (FP) plus friction loss.

MAIP = **FP** + friction loss (if applicable)

The **FP** (measured at the surface) must be calculated using the following equation:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

The values used in the equation are defined as:

"FG" is the fracture gradient of the injection zone in pounds per square inch/feet (psi/ft). The **FG** value for each well shall be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to the determine a representative **FG** may be used, if approved by the Director.

"SG" is the specific gravity of the injection fluid obtained from a representative fluid sample.

"D" is the true vertical depth in feet. The value for **D** is the depth of the top open perforation.

The current permitted MAIP is found in APPENDIX C. Historical permit files for the Tribal C-13 well indicate that the April 3, 2009 step rate was not considered valid. As a result, the authorized MAIP for the Tribal C-13 well was set at 0 psi in the February 2, 2010 authorization to inject letter. However, the MAIP may be revised using the above equation if a valid step rate test is run in the future.

(c) To revise the MAIP, the Permittee shall submit the following for review: step rate test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in APPENDIX A, that specifies the depth to top perforation). The MAIP shall be calculated as described above. The Director will review the information and may revise the MAIP in a written authorization.

(d) During the life of the Permit, the fracture gradient, top perforation depth, and specific gravity may change. When new perforations are added to the injection zone, the Permittee shall demonstrate that the FG previously submitted is also appropriate for the new interval within the injection zone. It may be necessary to run a new step rate test to gather information from the new interval proposed for injection. Upon submission of monitoring reports, tests, or well workover records that indicate one of these parameters has changed, the MAIP calculation will be evaluated.

When the D or FG value changes, a new MAIP shall be recalculated. When a sample analysis is submitted, the newly submitted SG value will be compared to the SG used to calculate the MAIP. If the absolute difference is greater than 0.05, the MAIP will be recalculated using the newly submitted SG value.

To approve an increase to the MAIP, resulting from changes to the D or FG values, the Director may also require an external (Part II) mechanical integrity demonstration at the increased MAIP.

The Director will notify the Permittee in writing of the revised MAIP. A newly calculated MAIP shall not be implemented until written approval is received from the Director.

(e) Tests to demonstrate external (Part II) Mechanical Integrity (MI) shall be conducted at the most recently approved MAIP. However, if during testing, the Permittee is unable to achieve the MAIP, the MAIP will be readjusted and set to the highest pressure achieved during the successful external (Part II) Mechanical Integrity Test (MIT). The Permittee will be notified in writing from the Director of the new MAIP, based on the Part II MIT results.

4. Injection Volume Limitation

Injection volume is limited to the total volume specified in APPENDIX C.

5. Injection Fluid Limitation

Injected fluids are limited to and the Permittee may inject those fluids described in APPENDIX C. However, prior to introduction of a new source (e.g. different production formation, well field, waste stream etc.) into the well, a fluid analysis shall be required, as listed in APPENDIX D under "PRIOR TO INTRODUCTION OF A NEW SOURCE." The Permittee shall provide a description of the fluid, including the process that generated the fluid, a representative sample of the new fluid source and a notification to the Director, as required in APPENDIX B. Results of the fluid analysis will be used to determine if a new MAIP is required. See Part II, Section B.4 *Injection Pressure Limitation*.

6. Tubing–Casing Annulus

The tubing-casing annulus (TCA) shall be filled with a non-corrosive fluid or other fluid approved by the Director. The TCA valve shall remain closed during normal operations and the TCA pressure shall be maintained between 0 (zero) and the lesser of either 100 psi or 10 percent of the tubing pressure.

If TCA pressure cannot be achieved, the Permittee shall report to EPA the actions taken to determine the cause of the excessive pressure and the proposed remedy. If a loss of MI has been determined, the Permittee shall comply with the *Loss of Mechanical Integrity* requirements found in Part II, Section C.5.

7. Alteration, Workover and Well Stimulation

Alterations, workovers and well stimulations shall meet all conditions of the Permit. Alteration, workover and well stimulation include any activity that physically changes the well construction (casing, tubing, packer) or injection formation.

Prior to beginning any addition or physical alteration to injection well construction or the injection formation, the Permittee shall give advance notice to the Director. Additionally, the Director's written approval must be obtained if the addition or physical alteration to the injection well modifies the approved well construction. Substantial alterations or additions may be cause for modification to the Permit and may include additional testing or monitoring requirements.

The Permittee shall record all alterations, workovers and well stimulations on a Well Rework Record (EPA Form 7520-19) and submit a revised well construction diagram, when the well construction has been modified. The Permittee shall provide this and any other record of well workover, logging or test data to EPA within thirty (30) days of completion of the activity.

The Permittee shall complete any activity which affects the tubing, packer or casing and provide demonstration of internal (Part I) MI within ninety (90) days of beginning the activity. If the Permittee is unable to complete work within the specified time period, the Permittee shall propose an alternative schedule and obtain the Director's written approval. Injection operations shall not resume until the well has successfully demonstrated MI. If the well lost MI, the Permittee must receive written approval from the Director to recommence injection.

8. *Well Logging and Testing*

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

Section C. MECHANICAL INTEGRITY

1. *Requirement to Maintain Mechanical Integrity*

The Permittee is required to ensure the injection well maintains MI at all times. Injecting into a well that lacks MI is prohibited.

An injection well has MI if:

(a) there is no significant leak in the casing, tubing or packer (internal Part I); and

(b) there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (external Part II).

2. *Demonstration of Mechanical Integrity*

The conditions under which the Permittee shall conduct the MI testing are as follows and detailed in APPENDIX B:

(a) Prior to receiving authorization to inject and periodically thereafter as specified in APPENDIX B, the Permittee shall demonstrate both internal Part I and external Part II MI. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are specified in APPENDIX B.

(b) After any rework that compromises the MI of the well and after a loss of MI.

Other than during periods of well workover (maintenance) in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the Permittee shall monitor injection tubing pressure, injection rate and volume, pressure on the annulus between tubing and casing, and bradenhead pressure, as specified in APPENDIX D.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from the injection activity.

Results of any MIT results required by this Permit shall be submitted to the Director as soon as possible but no later than thirty (30) calendar days after the test is complete.

3. *Mechanical Integrity Test Methods and Criteria*

EPA approved methods shall be used to demonstrate MI. These methods may be found in documents available from EPA at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance:

- *"Ground Water Section Guidance No. 34: Cement Bond Logging Techniques and Interpretation"*
- *"Ground Water Section Guidance No. 39: Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity"*
- *"Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations"*
- *"Temperature Logging for Mechanical Integrity"*

Current versions of these documents will also be available from EPA upon request. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

4. Notification Prior to Testing

The Permittee shall notify the Director at least thirty (30) calendar days prior to any MIT. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the MIT or EPA declines to witness the test. Notification may be in the form of a yearly or quarterly schedule of planned MITs, or it may be on an individual basis.

5. Loss of Mechanical Integrity

If the well fails to demonstrate MI during a test or a loss of MI becomes evident during operation (such as presence of pressure in the tubing-casing annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within twenty-four (24) hours (see Part III, Section D.11(e) of this Permit), cease injection and shut-in the well within forty-eight (48) hours unless the Director requires immediate shut-in.

Within five (5) calendar days, the Permittee shall submit a follow-up written report that documents circumstances that resulted in the MI loss and how it was addressed. If the MI loss has not been resolved, the Permittee shall provide a report with the proposed plan and schedule to reestablish MI. A demonstration of MI shall be reestablished within ninety (90) calendar days of any loss of MI unless written approval of an alternate time period has been given by the Director.

Injection operations shall not resume until after the MI loss has been resolved, the well has demonstrated MI pursuant to 40 CFR § 146.8, and the Director has provided written approval to resume injection.

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency

Monitoring parameters are specified in APPENDIX D. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D, even when the well is not operating. In the event the well has not injected or is no longer injecting, the monitoring report will reflect its status. Sampling data shall be submitted if the well has injected any time during the reporting period.

Records of monitoring information shall include:

(a) the date, exact place, and time of the observation, sampling or measurements;

(b) the individual(s) who performed the observation, sampling or measurements;

(c) the date(s) of analyses and individuals who performed the analyses;

(d) the analytical technique or method used; and

(e) the results of such analyses.

2. Monitoring Methods

Observations, measurements and samples taken for the purpose of monitoring shall be representative of the monitored activity and include:

(a) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in 40 CFR § 136.3 or by other methods that have been approved in writing by the Director.

(b) Injection tubing, TCA annulus, bradenhead pressures, injection rate, injected volume and cumulative injected volume shall be observed and recorded at the wellhead. All parameters shall be observed simultaneously to provide a clear indication of well operation. Annulus pressure applied during

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standard annulus pressure tests performed during MITs should not be included in the annual monitoring report.

(c) Pressures are to be measured in pounds per square inch (psi).

(d) Fluid volumes are to be measured in standard oil field barrels (bbl) or thousands of cubic feet (MCF).

(e) Injection rates are to be measured in barrels per day (bbl/day) or thousands of cubic feet per day (MCF/day).

3. Records Retention

The Permittee shall retain records of all monitoring information, including the following:

(a) Calibration and maintenance records and all original recordings for continuous monitoring instrumentation, copies of all reports required by this Permit, for a period of at least (3) years from the date of the sample, measurement or report. This period may be extended any time prior to its expiration by request of the Director.

(b) Nature and composition of all injected fluids until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6). The Permittee shall continue to retain the records after the three-year (3) retention period unless the Permittee delivers the records to the Regional Administrator, or his/her authorized representative, or obtains written approval from the Regional Administrator, or his/her authorized representative, to discard the records.

4. Annual Reports

Regardless of whether or not the well is operating, the Permittee shall submit an Annual Report to the Director that:

(a) summarizes the results of the monitoring required in Part II, Section D and APPENDIX D;

(b) includes a summary of any major changes in characteristics or sources of injected fluid. The report of fluids injected during the year must identify each new fluid source by well name and location, and the field name or facility name; and

(c) includes any new wells or well modifications within the area of review that have not previously been submitted. For those wells that penetrate the injection zone, a well construction diagram, cement records and cement bond log are also required.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if the EPA form indicates otherwise. An electronic form may also be obtained from EPA to satisfy reporting requirements.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

The Permittee shall notify the Director in writing at least thirty (30) days prior to plugging and abandoning an injection well. The notification shall include any anticipated changes to the plugging and abandonment plan (P&A Plan), which will be incorporated into the Permit as a modification.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids into or between USDWs, in accordance with 40 CFR § 146.10. Additional federal, state or local laws or regulations may also apply.

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3. Approved Plugging and Abandonment Plan

The approved P&A Plan and required tests are incorporated into this Permit as APPENDIX E. Changes to the approved P&A Plan will be incorporated into the Permit as a modification prior to beginning plugging operations and shall be submitted using EPA Form 7520-19. The Director also may require revision of the approved P&A Plan at any time prior to plugging the well.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-19) to the Regional Administrator or his/her authorized representative. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) a statement that the well was plugged in accordance with the approved P&A Plan; or

(b) where actual plugging differed from the approved P&A Plan found in APPENDIX E, an updated version of the plan, specifying the differences.

5. Wells Not Actively Injecting

After any period of two (2) years during which there is no injection, or two (2) years from the spud date of a newly drilled well or the permit effective date of a well to be converted to an injector, the Permittee shall plug and abandon the well in accordance with Part II, Section E.2 and APPENDIX E of this Permit unless the Permittee:

(a) provides written notice to the Regional Administrator or his/her authorized representative, prior to the two-year (2) period;

(b) describes actions or procedures, satisfactory to the Regional Administrator or his/her authorized representative, that the Permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells, unless waived by the Regional Administrator or his/her authorized representative; and

(c) receives written notice by the Regional Administrator or his/her authorized representative to temporarily waive plugging and abandonment requirements.

The Permittee of a well that has been temporarily abandoned shall notify the Director prior to resuming operation of the well.

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PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. CHANGES TO PERMIT CONDITIONS

1. Modification, Revocation and Reissuance, or Termination

The Director may, for cause, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversion to Non-UIC Well

The Director may allow conversion of the well to a non-UIC well. Conversion may not proceed until the Permittee receives written approval from the Director, at which time this Permit will expire due to the end of operating life of the facility. Once expired under this part, the Permittee will need to reapply for a UIC permit and restart the complete permit process, including opportunity for public comment, before injection can occur.

Conditions of such conversion shall include approval of the proposed well rework, demonstration of mechanical integrity and documentation that the well is authorized by another regulatory agency.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit may be transferred by the Permittee to a new owner or operator only if:

(a) the Permit has been modified or revoked and reissued (under 40 CFR § 144.39(b)(2)), or a minor modification made (under 40 CFR § 144.41(d)), to identify the new permittee and incorporate such other requirements as may be necessary under the SDWA, or

(b) the Permittee provides written notification (EPA Form 7520-7) to the Director at least thirty (30) days in advance of the proposed transfer date and submits a written agreement between the existing and proposed new permittees containing a specific date for transfer or permit responsibility, coverage, and liability between them, and demonstrates that the financial responsibility requirements of 40 CFR § 144.52(a)(7) have been met by the proposed new permittee. If the Director does not notify the Permittee and the proposed new permittee of his or her intent to modify or revoke and reissue, or modify, the transfer is effective on the date specified in the written agreement. A modification under this paragraph may also be a minor modification under 40 CFR § 144.41.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within thirty (30) days.

Section B. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby. Additionally, in a permit modification, only those conditions to be modified shall be reopened. All other aspects of the existing permit shall remain in effect for the duration of the permit.

Section C. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR part 2 (Public Information). Claims of confidentiality for the following information will be denied:

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- the name and address of the Permittee; and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section D. ADDITIONAL PERMIT REQUIREMENTS

1. ***Prohibition on Movement of Fluid Into a USDW***

The Permittee shall not construct, operate, maintain, convert, plug, abandon or conduct any other injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs, except as authorized by 40 CFR part 146.

2. ***Duty to Comply***

The Permittee must comply with all conditions of this Permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration as such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

3. ***Need to Halt or Reduce Activity Not a Defense***

The Permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. ***Duty to Mitigate***

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. ***Proper Operation and Maintenance***

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances), which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. ***Permit Actions***

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any Permit condition.

7. ***Property and Private Rights; Other Laws***

This Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other federal, state or local law or regulations.

8. ***Duty to Provide Information***

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with this Permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. ***Inspection and Entry***

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

(d) sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements

All applications, reports or other information submitted to the Regional Administrator or his/her authorized representative shall be signed and certified according to 40 CFR § 144.32. This section explains the requirements for persons duly authorized to sign documents and provides wording for required certification.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit shall be signed and certified in accordance with the requirements under Part III, D.10 of this Permit and shall be submitted to EPA:

UIC Enforcement, Mail Code: 8ENF-WSD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

All correspondence should reference the well name and location and include the EPA Permit number.

(a) *Monitoring Reports.* Monitoring results shall be reported at the intervals specified elsewhere in this Permit.

(b) *Planned changes.* The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted well, and prior to commencing such changes.

(c) *Anticipated noncompliance.* The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

(d) *Compliance schedules.* Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than thirty (30) calendar days following each schedule date.

(e) *Twenty-four hour reporting.* The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) any monitoring or other information, which indicates that any contaminant may cause an endangerment to a USDW; or

(ii) any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region 8 UIC Program SDWA Enforcement Supervisor, or by contacting EPA Region 8 Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) calendar days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue;

and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) *Other Noncompliance.* The Permittee shall report all instances of noncompliance not reported under Paragraphs 11(a), 11(b), 11(d), or 11(e) of this Section at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(g) *Other information.* Where the Permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall submit such facts or information to the Director within thirty (30) days of discovery of failure.

(h) *Oil Spill and Chemical Release Reporting.* The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802 or NRC@uscg.mil.

Section E. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§144.51(o) and 146.10, and the Permittee has submitted a plugging and abandonment report pursuant to 40 CFR §144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new Permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Types of Adequate Financial Responsibility.

Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,

(b) a letter of credit with a standby trust agreement,

(c) a fully funded trust agreement, or

(d) a financial test and corporate guarantee.

A standby trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and must accompany any surety bond or letter of credit. Annual reports from the financial institution managing the standby trust account shall be submitted to the Director showing the available account balance.

A surety bond acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://fiscal.treasury.gov/surety-bonds/circular-570.html.

A letter of credit acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and be issued by a bank or other institution whose operations are regulated and examined by a state or federal agency.

A fully funded trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA. Annual reports from the financial institution managing the trust account shall be submitted to the Director showing the available account balance.

An independently audited financial test with a corporate guarantee acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and shall demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet EPA's requirements including, but not limited to, total net worth to be able to use this method. If this financial instrument is used, it must be resubmitted annually, within ninety (90) calendar days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year. If at any time the Permittee does not meet the financial ratios, notice to EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

The Permittee shall submit a completed, originally-signed financial responsibility demonstration to:

UIC Financial Responsibility Coordinator
Mail Code: 8ENF-WSD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

3. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, may be required to adjust the given cost for inflation or pursue a new cost estimate as prescribed by the Director.

4. Insolvency

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism;

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) calendar days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

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APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The well shall be cased and cemented to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.22 and other applicable federal, state or local laws and regulations. General requirements include:

- The well shall be completed with at least two cemented casing strings set within a drilled hole, in addition to either a driven or cemented conductor pipe.
- Surface casing shall be cemented from the casing shoe to the surface and care shall be taken to maximize cement fill and bond in the annulus behind the casing.
- The casing and cement used in the construction of the well shall be designed for the life expectancy of the well, including the natural and applied pressures expected during the life of the well.
- At no time shall the permittee conduct any activity that endangers any USDW, as prohibited by 40 CFR § 144.12.
- The well shall be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 100 feet of the top of the authorized injection zone.

WELL CONSTRUCTION:

16-inch (in.), #55 conductor casing in a 19-in. hole to a depth of 81 feet-Kelly Bushing (ft-KB). Cemented with 100 sacks of Class G cement from 13 to 91 ft-KB. Ground elevation is 5,751 ft.

10-3/4-in. J-55, #40.5 surface casing set in a 13-3/4-in. hole to a depth of 711 ft-KB. Cemented with 430 sacks of Class G cement from 13 to 717 ft-KB.

7-in. N-80, #23 long string casing set in an 8-3/4-in. hole to a depth of 6,862 ft-KB. Cemented with 1,200 sacks of 12.2 pound per gallon (ppg), Class G cement from 4,610 to 6,862 ft-KB. The 8-3/4-in. was subsequently cemented from 717 to 2,181 ft-KB during workover to squeeze hole in casing from 1,370 to 1,400 ft-KB on March 26, 2009.

3-1/2-in. with internal plastic-coated tubing installed with a nickel-coated packer set at the depth of about 6,609-6,616 ft-KB (no more than 100 feet above the top perforation).

No well stimulation program is proposed as a result of the conversion of the well from a Class II Enhanced Oil Recovery Well to a Class II SWD well. In the event the Permittee wishes to conduct well stimulation, the Permittee shall follow the requirements in Part II, Section B.8. *Alteration, Workover, and Well Stimulation*.

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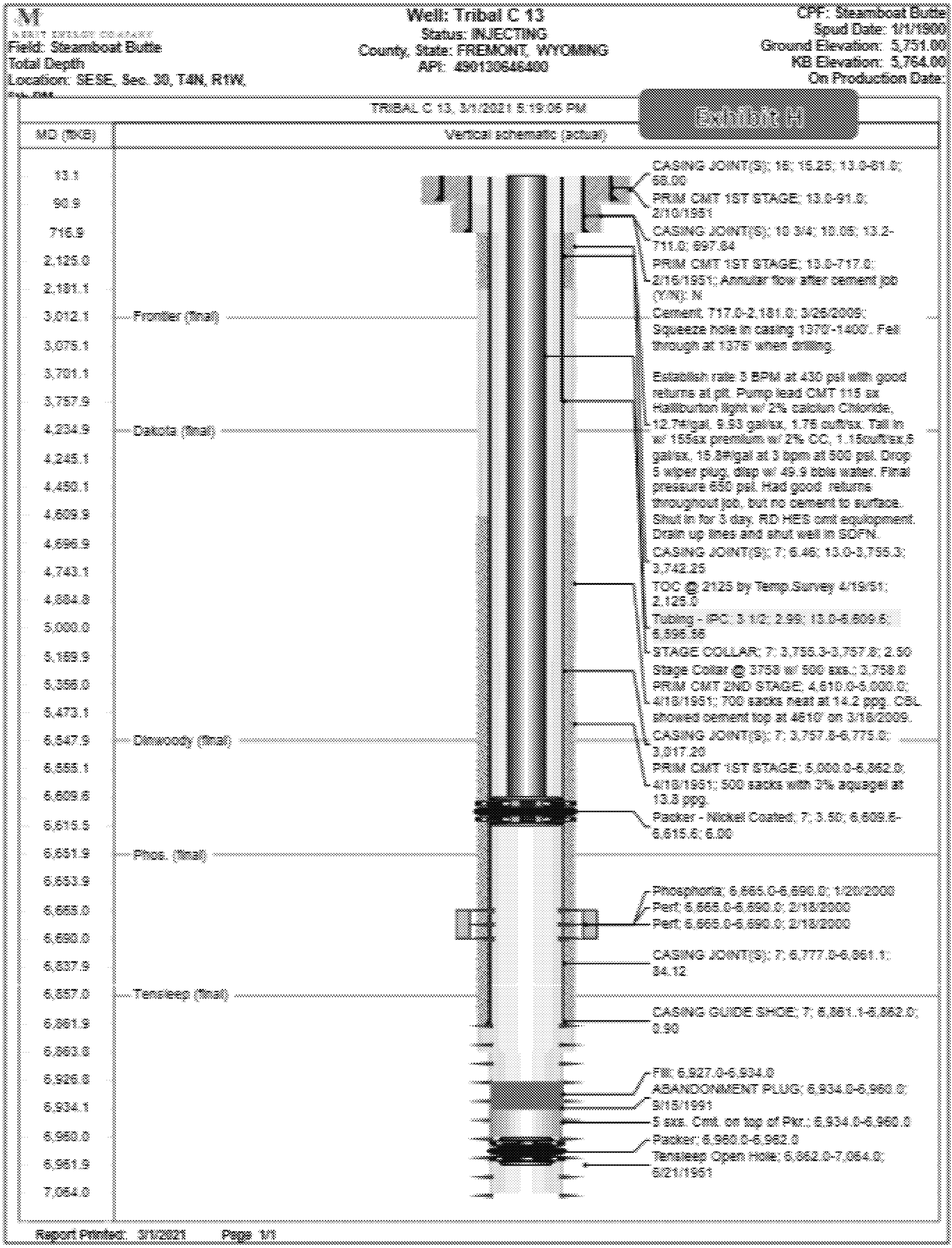
INJECTION WELL CONSTRUCTION DIAGRAM



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APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Well logging and tests shall be performed according to EPA approved procedures. It is the responsibility of the Permittee to obtain and use these procedures prior to conducting any well logging or test required as a condition of this Permit. These procedures can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Well logs and test results shall be submitted to the Director within sixty (60) calendar days, unless otherwise specified, of completion of the logging or testing activity and shall include a report describing the methods used during logging or testing and an interpretation of the log or test results. When applicable, the report shall include a descriptive report prepared by a knowledgeable log analyst, interpreting the results of that portion of those logs and tests which specifically relate to: (1) a USDW and the confining zone adjacent to it, and (2) the injection zone and adjacent formations.

LOGS, TESTS AND CORRECTIVE ACTION

TYPE OF LOG, TEST OR CORRECTIVE ACTION	DATE DUE
Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity.	
Corrective Action Corrective Action shall be completed in accordance with the requirements contained in Appendix F.	Prior to operation of the Tribal C-13 as a SWD well or within one (1) year of permit issuance, whichever is sooner. If periodic testing is required, the results shall be submitted in accordance with the schedule outlined in the approved corrective action plan.
Injectate Water Analysis A representative water sample of the injectate shall be analyzed for the constituents found in APPENDIX D.	1. Annually 2. Prior to the introduction of a new source; additional analytes may be requested on a case by case basis.
Injection Formation Reservoir Pressure The static reservoir pressure shall be recorded using a downhole pressure bomb.	Prior to operation of the Tribal C-13 as a SWD well or within one (1) year of permit issuance, whichever is sooner.
Standard Annulus Pressure (internal Part I MI) If the well has not received authorization to inject and does not have tubing installed, in lieu of the Standard Annulus Pressure test, a Casing Pressure Test can be performed.	1. Prior to receiving Authorization to Inject or within two (2) years of the permit effective date. 2. Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. 3. At least once every five (5) years after the last successful demonstration of internal (Part I) Mechanical Integrity.
Temperature Log (external Part II MI) Periodic demonstration of external Part II MI is required because the 3/18/09 cement bond log did not show a sufficient interval of 80 percent bond index or	1. Initial temperature log will be conducted between 6 to 12 months after permit issuance. 2. Subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.

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greater through the upper confining zone, per the authorization to inject letter dated February 2, 2010.	

APPENDIX C

OPERATING REQUIREMENTS

FLUID LIMITATION:

Injected fluids are limited to those: (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of hydrocarbons which are liquid at standard temperature and pressure.

Other than produced water generated by the permittee in the Steamboat Butte Field, fluids intended for disposal in the Tribal C-13 well will not by co-mingled with fluids injected for enhanced oil recovery in other Class II wells connected to the C-3 Battery. Specifically, an approved plan must be maintained and implemented to segregate fluids intended for disposal from fluids intended for enhanced oil recovery at the C-3 Battery.

This Permit does not allow for the injection of any hazardous waste as defined in 40 CFR 261.3. Injection of any substance defined as a hazardous waste, whether hazardous by listing or characteristic, is a violation of this permit and requires notification under Part III, Section D.11. Additionally, non-hazardous fluids that do not fall within the above definition for a Class II fluid defined in 40 CFR 144.6(b) are not approved for injection.

Examples of fluids which may be approved under Part II, Section B.6 include, but are not limited to: produced water, drilling fluids, used well completion, treatment, and stimulation fluids, basic sediment, water and other tank bottoms from oil and gas production storage facilities, well workover waste, liquid hydrocarbons removed from the production stream but not from oil refining, gases from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons, waste crude oil from primary field operations, and materials ejected from a producing well during blowdown.

Examples of prohibited fluids include, but are not limited to: unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, painting wastes, waste solvents, oil and gas service company wastes, vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, refinery wastes, liquid and solid wastes generated by crude oil and tank bottom reclaimers, used equipment lubricating oils, waste compressor oil, filters, and blowdown, used hydraulic fluids, waste in transportation pipeline related pits, caustic or acid cleaners, boiler cleaning wastes, boiler refractory bricks, boiler scrubber fluids, sludges, and ash, incinerator ash, laboratory wastes, sanitary wastes, pesticide wastes, radioactive tracer wastes, and groundwater remediation waste.

INJECTION ZONE:

Injection is permitted only within the approved injection zone listed below.

APPROVED INJECTION ZONE

FORMATION NAME or STRATIGRAPHIC UNIT	TOP (ft-KB) *	BOTTOM (ft-KB) *
Phosphoria	6,654	6,838
Tensleep	6,838	6,960[1]

*estimated top and bottom depths of formations based on a KB of 13 feet.

[1] Fluids may migrate below the existing open-hole completion at 6,960 feet as long as the fluids remain within the Tensleep Formation with an estimated basal depth of 7,331 feet.

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MAXIMUM ALLOWABLE INJECTION PRESSURE:

The parameters below are the values used to calculate the initial authorized MAIP issued with this Permit. These parameters may be updated throughout the life of well, pursuant to the conditions and formula at Part II.B.4 of this Permit. Documentation to support a change shall be provided and approved by the Director prior to recalculation of the MAIP.

MAIP Parameters

Fracture Gradient	Specific Gravity*	Depth (ft)	Friction Loss (psi)	Calculated MAIP (psi)	Authorized MAIP (psi)
N/A	1.054 [1.004 + 0.05]	6,654	N/A	N/A	0[1]

**From the MAIP equation in Part II, Section B.4(b), SG+0.05 or 1.050. SG of 1.004 from 2019 annual injectate fluid sample.*

[1] Historical permit files for the Tribal C-13 well indicate that the April 3, 2009 step rate was not considered valid. As a result, the authorized MAIP for the Tribal C-13 well was set at 0 psi in the February 2, 2010 authorization to inject letter.

MAXIMUM INJECTION VOLUME:

The maximum total volume permitted to be injected during the life of the well is 6,130,000 barrels to ensure fluids remain within the ¼ mile AOR and area aquifer exemption boundary.

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APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the Part II, Section D of the Permit, for detailed requirements for observing, recording and reporting of these parameters.

EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report. An electronic form may also be obtained from EPA to satisfy reporting requirements.

OBSERVE WEEKLY AND RECORD MONTHLY	
OBSERVE AND RECORD	Injection Tubing Pressure (psi)
	Bradenhead Pressure (psi)
	Annulus Pressure (psi)
	Injection Rate (bbl/day)
	Injected Volume (bbl)
	Cumulative Fluid Volume Injected (since injection began) (bbls)

WITHIN 30 DAYS AFTER AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE Analytical methods used must comply with the methods cited in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed below	
ANALYZE	Analyze a sample of injection fluids for the following constituents: • Total Dissolved Solids (mg/L) via Method 2540 C-97 • pH via Method 4500-H+ B-00 • Specific gravity via Method SM 2710 F • Conductivity/Specific Conductance (S/m) via Method 2510 B-97 • Cations: B, Ba, Ca, Fe, K, Li, Mn, Mg, Na, and Sr via EPA Method 200.7, 200.8 • Anions: Br, I, Cl and SO_4 via Method D6508, Rev. 2 HCO_3 via Method SM 2320 B CO_3 via Method 310.1 • Ammonia as N via Method 350.1, 350.2 or 350.3 • Uranium and Radium via Method 7500 Alternative analysis methods may be used, if pre-approved.

ANNUALLY (if injection occurred during reporting period) Analytical methods used must comply with the methods cited in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed below

<table>
<tr><td>ANALYZE</td><td>Analyze a sample of injection fluids for the following constituents:

• Total Dissolved Solids (mg/L) via Method 2540 C-97
• pH via Method 4500-H+ B-00
• Specific gravity via Method SM 2710 F
• Conductivity/Specific Conductance (S/m) via Method 2510 B-97

Alternative analysis methods may be used, if pre-approved.</td></tr>
</table>

ANNUALLY	
REPORT	Each month's maximum and average injection tubing pressures (psi)
	Each month's maximum and minimum annulus pressures (psi)
	Each month's maximum and minimum bradenhead pressures (psi)
	Each month's maximum and average injection rate (bbl/day)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written laboratory analytical results of annual injected fluid analysis
	Sources of all fluids injected during the year, including any wellfield and formation, noting any major changes in characteristics of injected fluid.

In addition to these items, additional logging and testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B – LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT (P&A) REQUIREMENTS

All wells shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids either into or between USDWs in accordance with 40 CFR § 146.10. Additional federal, state or local law or regulations may also apply. General requirements applicable to all wells include:

- Prior to plugging a well, mechanical integrity must be established unless the P&A plan will address the mechanical integrity issue. Injection tubing shall be pulled.
- Cement plugs shall have sufficient compressive strength to maintain adequate plugging effectiveness.
- Each plug placement, unless above a retainer or bridge plug, must be verified by tagging the top of the plug after the cement has had adequate time to set.
- A minimum 50 feet surface plug is required inside and, if necessary, outside of the surface casing, to seal pathways for fluid migration into the subsurface.
- If there is more than 2,000 mg/L difference of TDS between individual exposed USDWs, they must be isolated from each other.
- Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal must be used during plugging operations and should remain between plugs in the well after cement plug placement.

At a minimum, the following plugs are required:

1. **Isolate the Tensleep Formation**
   PLUG #1: Set a cast iron cement retainer (CICR) at least 100 feet above the 7-inch casing shoe or at 6,784 feet. Squeeze off 6.25-inch open hole and 7-inch casing from below the retainer at 6,784 to 6,960 feet. Set a 20 foot balance plug above the cement retainer between the interval of 6,764 to 6,784 feet.

2. **Isolate the Phosphoria Formation**
   PLUG #2: Set a CICR at least 100 feet above the top perforation or at 6,540 feet inside the 7-inch casing. Squeeze interval of the Phosphoria perforations and fill casing from 6,540 to 6,690 feet inside the 7-inch casing. Set a 40 foot balance plug above the CICR between the intervals of 6,500 to 6,540 feet inside the 7-inch casing.

3. **Isolate the Frontier and Mowry Shale**:
   PLUG #3: Set a CICR at approximately 3,760 feet within the Mowry Formation. Perforate, attempt to establish circulation, and squeeze a sufficient volume of cement to extend at least 50 feet above and 50 feet below the contact between the Frontier Formation and the Mowry Shale behind the 7-inch casing. This is depicted by the purple rectangles in the original P&A diagram. Set a 20 foot balance plug above the CICR between the intervals of 2,875 to 3,760 feet inside the 7-inch casing.

   This portion of the original P&A procedure was modified to ensure a cement barrier exists to prevent movement of fluids behind the 7-inch casing between USDWs above and below the Mowry Shale. Specifically, well records indicate that an uncemented interval exists behind the 7-inch casing from 2,181 to 4,610 feet.

4. **Isolate Surface Fluid Migration Paths**:
   PLUG #4: Set a balance plug from the surface to a depth of 742 feet inside and on the backside of the 7-inch casing.

Modifications to this plan may be required based on the results of review of the well's periodic external (Part II) MI demonstration and well completion and cementing records.

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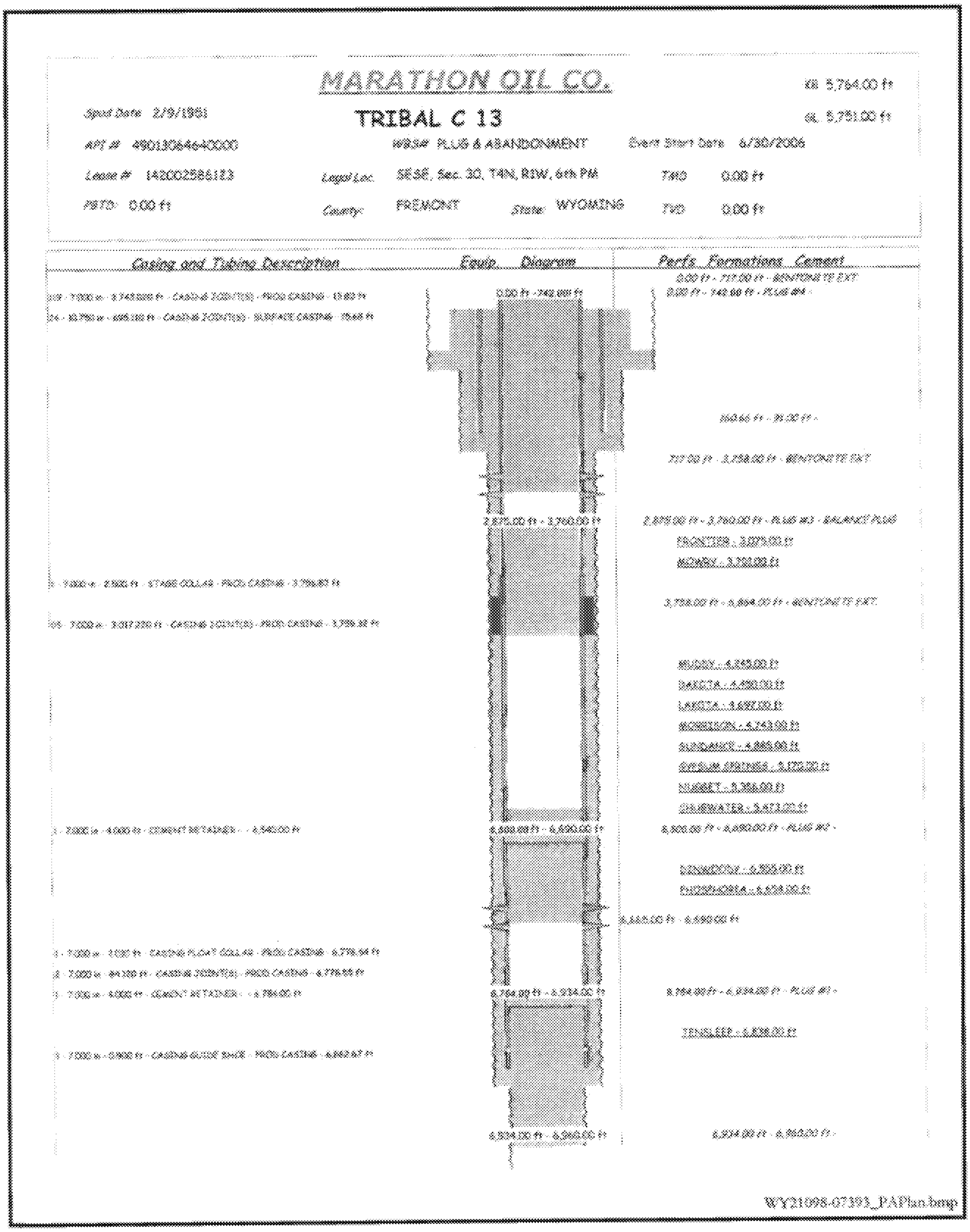
INJECTION WELL P&A DIAGRAM



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APPENDIX F

CORRECTIVE ACTION PLAN

A review of well completion and P&A records for wells located within the AOR identified two (2) wells requiring corrective action under this Permit. Corrective action is necessary to ensure that injected fluids remain in the authorized injection zone as required in Part II, Section B.2 of this Permit. The wells are listed in the table below.

Well Name	Location	API #
Tribal C-45	Sec 29, T4N-R1W	49-013-22109
Tribal C-37	Sec 29, T4N-R1W	49-013-21916

Corrective Action Requirements

Tribal C-45 Corrective Actions:
One of the following corrective action(s) must be completed prior to operation of the Tribal C-13 as a SWD well or within one (1) year of permit issuance, whichever is sooner:

1. Isolation of the Phosphoria and Tensleep Formations from the Muddy Sandstone within the well will be maintained continuously, and a demonstration will be made to show that no fluid movement is occuring through the CICR set at 6,637 ft-KB within one (1) year of permit issuance and at least once every five (5) years thereafter. This demonstration shall be performed under a plan describing the proposed testing method (e.g. casing pressure test of the CICR) submitted for EPA review, comment and approval, and the results of the testing shall be submitted to the Director within thirty (30) calendar days after the test is complete.

2. The open perforations in the Phosphoria and Tensleep Formations and/or Muddy Sandstone are permanently plugged and abandoned in the Tribal C-45 well, resulting in permanent isolation of the zones from one another. A plan will be submitted for EPA review, comment and approval prior to implementing the procedure. The plan will include notice and approval where required by applicable federal, tribal or local regulatory jurisdictions.

   Following completion of the corrective action, the Permittee will submit a report for EPA review, comment and approval. The report will document the field activities, summarize any deviations from the approved plan, include an updated wellbore diagram, and demonstrate to the satisfaction of the Director that the wellbore cannot act as a conduit for movement of fluids out of the injection zone of the Tribal C-13 well.

3. Alternatively, the Permittee may propose and implement another method of corrective action to demonstrate that the wellbore will not act as a conduit for fluid movement out of the approved injection zone. Any such alternate proposal is subject to approval by the Director and may require modification of this Permit.

Tribal C-37 Corrective Actions:
One of the following corrective action(s) must be completed prior to operation of the Tribal C-13 as a SWD well or within one (1) year of permit issuance, whichever is sooner:

1. The Permittee will withdraw the May 7, 2004 request to the U.S. BLM to co-mingle production from the Muddy Sandstone with production from the Phosphoria and Tensleep Formations. No co-mingling of production from the Muddy Sandstone with production from the Phosphoria and Tensleep Formations will be pursued for the Tribal C-37 well in the future.

2. The Permittee will prepare a revised Sundry Notice to the U.S. BLM with a plan for recompletion of the C-37 well in the Muddy Sandstone that includes isolation of the Muddy Sandstone from the Phosphoria and Tensleep Formations. EPA will be given an opportunity to review, comment and approve this revised plan as it relates to

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the operation of the Tribal C-13 injection well and potential for fluid movement out of the authorized injection zone. Periodic monitoring or testing may be required as a condition of approval to demonstrate that zonal isolation exists between production zones.

3. Alternatively, the Permittee may propose and implement another method of corrective action to demonstrate that the wellbore will not act as a conduit for fluid movement out of the approved injection zone. Any such alternate proposal is subject to approval by the Director and may require modification of this Permit.

STATEMENT OF BASIS

Merit Energy Company
Tribal C-13
Fremont County, Wyoming

Class II Salt Water Disposal Well
WY21098-07393

CONTACT: Chris Brown
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-6669
Email: Brown.Christopher.T@epa.gov

This Statement of Basis gives the derivation of site-specific Underground Injection Control (UIC) permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in WY21098-07393 (Permit).

U.S. Environmental Protection Agency (EPA) UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water (USDWs). EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR parts 2, 124, 144, 146 and 147, and address potential impacts to USDWs. In accordance with 40 CFR § 144.35, issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR § 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147) are not discussed in this document. Regulations specific to Indian country injection wells in Wyoming are found at 40 CFR § 147.2553.

Upon the Effective Date when issued, the Permit authorizes the operation of the injection well so that the injection does not endanger USDWs. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR § 144.40 and can be modified or revoked and reissued under 40 CFR § 144.39 or § 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to an approved state or tribal program, unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a tribal or state permit.

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PART I. General Information and Description of Project

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

hereinafter referred to as the "Permittee," submitted an application for an UIC Program permit for the following injection well or wells:

Tribal C-13
320' FEL & 994' FSL, Section 30, T4N, R1W
Fremont County, Wyoming

The application, including the required information and data necessary to issue or modify a UIC permit in accordance with 40 CFR parts 2, 124, 144, 146 and 147, was reviewed and determined by EPA to be complete.

Project Description

The Permittee is proposing to convert the existing Tribal C-13 well from a Class II Enhanced Oil Recovery (EOR) well to a Class II Salt Water Disposal (SWD) well. The existing UIC permit (WY21098-07393) became effective on December 24, 2008, and authorization to inject was granted on February 2, 2010. The existing UIC permit allows injection of Class II fluids into the Tensleep and Phosphoria Formations for the purpose of enhanced recovery of oil or natural gas. The conversion to a Class II SWD well would allow for the injection of Class II fluids for the purpose of disposal into the same formations. As defined in 40 Code of Federal Regulations § 146.5, a Class II well injects fluids:

1. Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.
2. For enhanced recovery of oil or natural gas; and
3. For storage of hydrocarbons which are liquid at standard temperature and pressure.

The Permittee has proposed a maximum daily injection rate of 8,500 barrels per day (bbl/d) and average daily injection rate of 5,000 bbl/d.

PART II. Permit Considerations (40 CFR § 146.24)

Hydrogeologic Setting

The Wind River Basin is located in the central portion of Wyoming and consists of more than 12,000 feet (ft.) of sedimentary rocks at its deepest. It is bounded to the north by the Absaroka and Owl Creek Mountains, to the east by the Casper Arch, to the south by the Granite Mountains, and to the west by the Wind River Mountains. The Tribal C-13 well is located within the Steamboat Butte Field in the northwestern portion of the basin.

The Tribal C-13 well has injected into the Phosphoria and Tensleep Formations since 2010. The Phosphoria Formation at the Tribal C-13 is 184 feet thick and reportedly has a net permeable thickness of 16 feet with an average porosity of 16.5% and permeability of 6.11 millidarcies (md). The Phosphoria Formation consists of medium crystalline gray dolomitic limestone with milky and white chert. However, injectivity profiles run for the Tribal C-13 well in 2009 and 2020 did not indicate movement of injected fluids into perforations within the interval of the Phosphoria Formation.

The Tensleep Formation at Tribal C-13 has a net permeable thickness of 237 ft. and is comprised of fine to medium grained white to brown stained sandstone with thin dolomitic sandstone interbeds. The Tensleep Formation reportedly has an average porosity of 13.1% and a permeability of 8.1 md. However, injectivity profiles run for the Tribal C-13 well in 2009 and 2020 indicate that 95% of the injected fluids are into an approximately 48 foot open-hole interval within the Tensleep Formation.

Table 2.1 provides a summary of formations and major stratigraphic units above and below the injection zone. Except as otherwise noted, all formation and stratigraphic unit depths are relative to the Tribal C-13 well.

TABLE 2.1
GEOLOGIC SETTING

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Lithology
Quaternary Sands	0	380	Sand
Cody Shale	380	3,075	Shale
Frontier	3,075	3,701	Sandstone/Shale
Mowry Shale	3,701	4,245	Shale
Muddy	4,245	4,348	Sandstone/Shale
Thermopolis Shale	4,348	4,450	Shale
Dakota	4,450	4,697	Sandstone/Shale
Lakota	4,697	4,743	Fluvial Sandstone
Morrison	4,743	4,885	Shale
Sundance	4,885	5,170	Sandstone/Shale laminations
Gypsum Springs	5,170	5,356	Anhydrite
Nugget	5,356	5,473	Sandstone
Chugwater	5,473	6,555	Sandstone/Shale
Dinwoody	6,555	6,654	Dolomite
Phosphoria	6,654	6,838	Dolomitic limestone
Tensleep	6,838	7,331$_1$	Sandstone
Amsden	7,331$_1$	7,449$_1$	Shale/Limestone and Dolomite w/ basal Darwin Sandstone member
Madison	7,449$_1$	--	Limestone

* depths are relative to a Kelly Bushing (KB) of 13 ft.

$_1$ Below the total depth (TD) of the Tribal C-13 well, depths estimated from gross thickness reported for the nearby Tribal E-26 well.

Injection Zone
An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zone(s) are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review (AOR).

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Porosity	Exemption Status	Exempted Area
Phosphoria	6,654	6,838	16.5	Exempted 11/25/1988	T3N, R1W - W/2 Sec. 4, Sec. 5, E/2 Sec. 6, NE/4 Sec. 8, W/2 Sec. 9. T4N, R1W - W/2 Sec. 29, E/2 Sec. 30, E/2 Sec. 31, Sec. 32.
Tensleep	6,838	6,960[1]	13.1	Exempted 11/25/1988	T3N, R1W - W/2 Sec. 4, Sec. 5, E/2 Sec. 6, NE/4 Sec. 8, W/2 Sec. 9. T4N, R1W - W/2 Sec. 29, E/2 Sec. 30, E/2 Sec. 31, Sec. 32.

* depths are approximate values at the wellbore

[1] Fluids may migrate below the existing open-hole completion at 6,960 feet as long as the fluids remain within the Tensleep Formation with an estimated basal depth of 7,331 feet. The basal depth was estimated from gross thickness reported for the nearby Tribal E-26 well.

Confining Zones
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The confining zone or zones are listed in TABLE 2.3.

The Dinwoody Formation overlies the Phosphoria Formation and is the upper confining zone. The Dinwoody Formation is 99 ft. thick and consists of dense limey dolomite and dolomitic shale. The Dinwoody Formation reportedly acts as a seal to trap oil and water in the Phosphoria Formation produced in the Steamboat Butte Field. Additionally, the Dinwoody is overlain by approximately 1,000 feet of the Chugwater Formation consisting of interbedded siltstone and shale that provides additional confinement with some limestone and sandstone. The permeable Crow Mountain Sandstone member occurs in the upper portion of the Chugwater Formation.

The upper portion of the Amsden Formation underlies the Tensleep Formation and is the lower confining zone. The upper portion of the Amsden Formation is approximately 62 ft. thick and consists of variable siliciclastic and interbedded carbonate sequences. Discontinuous lenticular zones of porous dolomite occur; however, these zones are reportedly encased in very fine, argillaceous and microcrystalline dolostones and tight marine shales that provide the confinement. The basal Darwin Sandstone member occuring at a depth of approximately 7,393 ft-KB, as estimated from the nearby Tribal E-26 well, is not considered part of the lower confining zone.

A major thrust fault associated with the Steamboat Butte anticline structure is located approximately 2,000 feet west of the Tribal C-13 well. This thrust fault reportedly has 1,500 feet of displacement and serves as the primary

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structural trap for oil-bearing zones in the Steamboat Butte Field. This assertion is supported by the presence of dry holes west of the fault; specifically, no production associated with the Tribal Q-1 well is reported in the Wyoming Oil and Gas Conservation Commission (WOGCC) database. The strike of the thrust fault is North 25 degrees West with an interpreted dip ranging from 30 to 45 degrees to the northeast, and no wells is the Steamboat Butte Field reportedly penetrate the principal plane of the reverse fault (Blackstone, 1998). A secondary reverse fault is reportedly located approximately 1,700 feet south of the Tribal C-13 well. This fault strikes roughly north-to-south, and the mapped location depicts it as dying out outside of the 1/4-mile AOR.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)	Base (ft)	Lithology
Dinwoody	6,555	6,654	Dense limey dolomite and dolomitic shale.
Amsden	7,331[1]	7,393[1]	Interbedded shale, limestone and dolomite. The basal Darwin Sandstone member is not considered part of the lower confining zone.

* Depths are approximate values at the wellbore based on KB of 13 feet
[1] Depths estimated from gross formation thickness reported for the nearby Tribal E-26 well.

Underground Sources of Drinking Water (USDWs)
Aquifers or the portions thereof which 1) currently supply any public water system or 2) contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contain fewer than 10,000 mg/l total dissolved solids (TDS), are considered to be USDWs.

Water quality samples from the Phosphoria and Tensleep Formations exhibit TDS concentrations less than 10,000 mg/L. Specifically, a sample collected from the Tensleep Formation at the Tribal C-13 well and included in the United States Geologic Survey (USGS) Produced Water Database v2.3 exhibited a TDS concentration of 2,480 mg/L. However, portions of the Phosphoria and Tensleep Formations located within the Steamboat Butte Field were exempted on November 25, 1988 upon the effective date of the UIC Program administered by EPA for the Wind River Indian Reservation. The areal extent of the existing aquifer exemption is described in 40 CFR 147.2554 and is included in Table 2.2 above.

Seven (7) formations exhibiting TDS concentrations less than 10,000 mg/L have been identified above the injection zone. Specifically, the Quaternary sands, water-bearing zones of the Cody Shale, Frontier Formation, Muddy Sandstone, Dakota Sandstone, Lakota Sandstone and the Nugget Sandstone are all considered USDWs. The Sundance Formation is not considered a USDW because the available water quality sample results indicate a TDS concentration greater than 10,000 mg/L. Additionally, the Chugwater Formation is primarily considered a confining zone and not a USDW; however, the USDW status of Crow Mountain Sandstone Member located in the upper portion of the Chugwater Formation is unknown due to the lack of available water quality sample results. Two (2) formations exhibiting TDS concentrations less than 10,000 mg./L were identified below the injection zone. These include the basal Darwin Sandstone member of the Amsden Formation and the Madison Limestone.

The nearest public water system (PWS) well is located approximately 6.25 miles southeast, and is associated with the Wyoming Department of Transportation, Diversion Dam rest area. According to records in the Wyoming State Engineer's Office e-permit database, this well is completed to a depth of 340 feet.

Table 2.4 provides a summary of information regarding known or estimated TDS concentrations above, below,

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and within the injection zone and provided in the permit application or otherwise identified by EPA. TDS concentration data identified in the United States Geologic Survey (USGS) Produced Water Database v2.3 was supplemented where noted in the table for formations with only one or no reported TDS concentration in the permit application.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)
Quaternary Sands	0	380	**700-2,800**
Cody Shale	380	3,075	**1,750-2,430**
Frontier	3,075	3,701	**4,383-7,630**
Muddy	4,245	4,348	**7,292-7,553**
Dakota	4,450	4,697	**4,534[2]-6,080**
Lakota	4,697	4,743	**7,463[2]**
Sundance	4,885	5,170	**11,693-58,294**
Nugget	5,356	5,473	**8,500-11,114**
Chugwater	5,473	6,555	--
Dinwoody	6,555	6,654	--
Phosphoria	6,654	6,838	**7,150**
Tensleep	6,838	7,331[1]	**2,480-5,600**
Amsden (Darwin Sandstone member)	7,331[1]	7,449[1]	**6,100[2]**
Madison	7,449[1]	--	**1,958-10,316[2,3]**

* Depths are approximate values at the wellbore based on KB of 13 feet.
[1] Depths estimated from gross thickness reported for the nearby Tribal E-26 well.
[2] Water quality sample results supplemented from USGS Produced Water Database v2.3
[3] The median TDS concentration from ten water samples collected form the Madison is 2,183 mg/L.

Reference: Blackstone, Jr., D. L., 1998. Faulting in Steamboat Butte and Pilot Butte anticlines, west-central Wyoming: a review. Contributions to Geology, University of Wyoming, v. 32, no. 2, p. 159-180.

PART III. Well Construction (40 CFR § 146.22)

The approved well construction, incorporated into the Permit as APPENDIX A, will be binding on the Permittee. Modification of the approved construction is allowed under 40 CFR § 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cement
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluid containing any contaminant into USDWs. Well construction details for the injection well(s) are shown in TABLE 3.1.

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Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of external (Part II) mechanical integrity.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft-KB)	Cemented Interval (ft-KB)
Conductor	19	16	13-81	13-91
Surface	13.75	10.75	13-717	13-717
Production	8.75	7	13-6,862	717-2,181 4,610-6,862
Tubing	7	3.5	13-6,616	--

Injection Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set within 100 feet above the top of the authorized injection zone. The tubing and packer are designed to prevent injection fluid from coming into contact with the production casing.

Tubing-Casing Annulus
The tubing-casing annulus (TCA) allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with non-corrosive fluid or other fluid approved by the Director.

Sampling and Monitoring Device
To fulfill permit monitoring requirements and provide access for EPA inspections, sampling and monitoring equipment will need to be installed and maintained. Required equipment includes but is not limited to: 1) pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the MAIP is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing(s), TCA, and surface casing-production casing (bradenhead) annulus; 3) a fluid sampling point between the pump house or storage tanks and the injection well, isolated by shut-off valves, for sampling the injected fluid; and 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR § 144.55)

Area of Review
Permit applicants are required to identify the location of all known wells within the AOR which penetrate the injection zone. Under 40 CFR § 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For area permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

The AOR for the Tribal C-13 well is a fixed radius of one-quarter (1/4) mile. There are ten (10) wells that penetrate the injection zone within the 1/4 mile AOR listed in Table 4.1. These wells include two (2) injection wells, three (3) production wells, three (3) temporarily abandoned production wells, one (1) monitoring well, and one (1) plugged and abandoned production well.

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TABLE 4.1

AOR Well Name	API	Well Type	Operating Status	Total Depth (ft-KB)	Distance (ft) /Direction from Tribal C-13[2]
Tribal C-3	49-013-06463	Production	Plugged and Abandoned	7,104	1,290 E
Tribal C-10	49-013-06454	Production	Temporarily Abandoned	7,047	1,315 S
Tribal C-14	49-013-06469	Injection	Active	7,167	1,315 N
Tribal C-23	49-013-06460	Injection	Active	7,050	615 S
Tribal C-37	49-013-21916	Production[1]	Active	7,198	1,180 SE
Tribal C-39	49-013-22017	Monitoring Well[1]	Active	7,179	1,225 NE
Tribal C-40	49-013-22015	Production[1]	Active	7,163	345 N-NE
Tribal C-42	49-013-22016	Production[1]	Temporarily Abandoned	7,145	665 SW
Tribal C-44	49-013-22110	Production[1]	Active	7,175	380 NW
Tribal C-45	49-013-22109	Production[1]	Temporarily Abandoned	7,150	650 E

Notes: [1]Deviated or horizontal well
[2] Approximate distance to the nearest of the surface or bottom hole locations

Based on a review of well construction information submitted with the permit application, two (2) wells exhibiting conditions warranting corrective action were identified. Specifically, these two (2) wells include the Tribal C-45 and Tribal C-37 wells. Potential conduits for injection of fluids out of the authorized injection zone were not identified in a review of the construction records for the remaining seven (7) wells.

Corrective Action Plan (CAP)
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

TABLE 4.2 lists the wells in the AOR that a CAP is required. The CAP will be incorporated into the Permit as APPENDIX F and becomes binding on the Permittee. The Permit requires that corrective action(s) must be completed prior to operation of the Tribal C-13 as a SWD well or within one (1) year of permit issuance, whichever is sooner.

TABLE 4.2
CAP TABLE

AOR Well Name	Well Type	Operating Status	Total Depth (ft-KB)	Top of Cement (ft-KB)	Corrective Action Plan
Tribal C-45	Production	Temporarily Abandoned	7,150	2,200	See Appendix F
Tribal C-37	Production	Active	7,198	Surface	See Appendix F

A summary of the reported well records is presented below:

<u>Tribal C-45:</u>
The Tribal C-45 well was drilled in 2001 and completed to a total depth of 7,150 ft-KB. Well completion records indicate that 7-inch production casing was cemented at 7,150 ft-KB with a top of cement of 2,200 ft-KB, as

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identified in a cement bond log run on July 6, 2001. The well was originally completed as a Phosphoria and Tensleep production well. However, in April 2017, the Muddy Sandstone was perforated between 4,226 and 4,237 ft-KB and acidized. A cast-iron cement retainer (CICR) was set at 6,637 ft-KB to temporarily isolate open perforations in the Phosphoria and Tensleep Formations and Muddy Sandstone from one another. The CICR was reportedly pressure tested to 500 psi and held for 30 minutes before being topped with 200 pounds of sand.

Based on a review of the information supplied in the application for the Tribal C-45 well, the CICR is the only barrier preventing the potential for fluid movement out of the injection zone of the Tribal C-13 well and into the open perforations in the overlying Muddy Sandstone through the Tribal C-45 wellbore. The Muddy Sandstone is not an exempted aquifer in the Steamboat Butte Field. Water quality samples included in the permit application or otherwise identified by EPA during review of the permit application indicate that the Muddy Sandstone is a USDW with TDS concentrations ranging from 7,292 to 7,553 mg/L.

In consideration of the criteria and factors contained in 40 CFR 146.7, the current CICR configuration does not represent an adequate means of permanent isolation of the Phosphoria and Tensleep Formations from the Muddy Sandstone to ensure the long-term protection of a USDW. Consequently, corrective action is necessary.

Tribal C-37:
A sundry notice was approved by the U.S. Bureau of Land Management (BLM) on May 7, 2004 to recomplete the Tribal C-37 well in the Muddy Sandstone with co-mingled production from the Phosphoria and Tensleep Formations. According to the wellbore diagram included with the Tribal C-13 application, the workover to recomplete the Tribal C-37 well with perforations in the Muddy Sandstone has not yet occurred. The Muddy Sandstone is not an exempted aquifer in the Steamboat Butte Field. Water quality samples included in the permit application or otherwise identified by EPA during review of the permit application indicate that the Muddy Sandstone is a USDW with TDS concentrations ranging from 7,292 to 7,553 mg/L.

In consideration of the criteria and factors contained in 40 CFR 146.7, co-mingled production of the Muddy Sandstone with production from the Phosphoria and Tensleep Formations represents a conduit for fluid movement out of the injection zone of the Tribal C-13 well and into a USDW. Consequently, corrective action is necessary.

PART V. Well Operation Requirements (40 CFR § 146.23)

Mechanical Integrity (40 CFR § 146.8)
An injection well has mechanical integrity (MI) if:

1. Internal (Part I) MI: there is no significant leak in the casing, tubing, or packer; and
2. External (Part II) MI: there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

The Permit requires MI to be maintained at all times. The Permittee must demonstrate MI prior to injection and periodically thereafter, as required in APPENDIX B Logging and Testing Requirements. A demonstration of well MI includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating internal (Part I) and external (Part II) MI are dependent upon well and are subject to change. Should well conditions change during the operating life of the well, additional requirements may be specified and will be incorporated as minor modifications to the Permit.

A successful internal Part I Mechanical Integrity Test (MIT) is required at a frequency of no less than five years after the last successful MIT. A demonstration of internal MI is also required following any workover operation that affects the tubing, packer or casing or after a loss of MI. In such cases, the Permittee must complete work and restore MI within 90 days following the workover or within the timeframe of the approved alternative schedule. After the well has lost MI, injection may not recommence until after internal MI has been demonstrated and the Director has provided written approval.

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Internal (Part I) MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, whichever is less, with a ten percent or less pressure loss over thirty minutes. However, since the current MAIP is 0 psi, the Internal (Part I) MI will be made using a pressure of 1,000 psi. Additional guidance for Internal (Part I) MI can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Periodic demonstration of External (Part II) MIT in APPENDIX B of the permit because the March 3, 2009 cement bond log did not show a sufficient interval of 80 percent bond index or greater through the upper confining zone, and periodic demonstration of Part II MIT was incorporated in the original authorization to inject letter dated February 2, 2010. As a result, a temperature survey is required between 6-12 months after permit issuance and once every five (5) years thereafter.

Injection Fluid Limitation

Injected fluids are limited to those: (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of hydrocarbons which are liquid at standard temperature and pressure.

This Permit does not allow for the injection of any hazardous waste as defined in 40 CFR 261.3. Injection of any substance defined as a hazardous waste, whether hazardous by listing or characteristic, is a violation of this permit and requires notification under Part III, Section D.11. Additionally, non-hazardous fluids that do not fall within the above definition for a Class II fluid defined in 40 CFR 144.6(b) are not approved for injection.

Prior to introduction of a new source (e.g. different production formation, well field, waste stream etc.) into the well, a fluid analysis is required, as listed in APPENDIX D under "PRIOR TO INTRODUCTION OF A NEW SOURCE." The Permittee must provide a description of the fluid, including the process that generated the fluid, a representative sample of the new fluid source and a notification to the Director, as required in APPENDIX B. Results of the fluid analysis will be used to determine if a new MAIP is required. See Part II, Section B.4 Injection Pressure Limitation.

Volume Limitation

Injection volume is limited to the total volume specified in APPENDIX C of the Permit.

The maximum total volume permitted to be injected during the life of the well is 6,130,000 barrels to ensure fluids remain within the existing 1/4-mile AOR and area aquifer exemption boundary. The volume limitation is calculated using the formula:

$$\mathbf{V} = (p\ \mathbf{r}^{2}\mathbf{t}\text{↲})/5.615$$

Where, V = maximum cumulative volume to be injected (bbl)

r = radial distance away from the wellbore that fluids have traveled, 1,320 ft

t = thickness of injection zone, 48 ft

↲ = porosity of injection zone, 0.131

p = 3.14159265

5.615 = conversion factor (barrels and ft^3)

Injectivity profiles run for the Tribal C-13 well in 2009 and 2020 indicate that 95% of the injected fluids are into the portion of the Tensleep Formation occuring between 6,862 ft-KB and 6,910 ft-KB. These depths correspond to the base of the casing guide shoe and depth of fill on top of the abandonment plug placed at 6,934 ft-KB. As a result, the injection zone thickness used in the volume limitation was estimated using a thickness of 48 feet.

Injection Pressure Limitation
40 CFR § 146.23(a)(1) requires that the injection pressure at the wellhead must not exceed a maximum calculated to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. In lieu of testing the fracture pressure of the confining zone, which may be impractical, the pressure in the injection formation provides a conservative surrogate.

The calculated Maximum Allowable Injection Pressure (MAIP) described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition.

Except during stimulation, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances shall injection pressure cause the movement of injection or formation fluids into a USDW.

The **MAIP** allowed under the Permit, as measured at the surface, will be calculated according to the equations below. The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using these equations. The Permit also specifies where the input values are derived from. Prior to authorization to commence injection, the Permittee must submit for review the necessary information to calculate the MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written authorization to commence injection.

The formation fracture pressure (**FP**) is the pressure above which injection of fluids will cause the rock formation to fracture. This equation, as measured at the surface, is defined as:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

Where, FG is the fracture gradient in psi/ft
SG is the specific gravity
D is the depth of the top perforation in feet

The **FG** value for each well will be determined by conducting a step rate test. The results of the test will be reviewed and approved by the Director. As appropriate, the FG may be determined by one of these other following methods:

- Representative **FG** values determined previously from valid tests in nearby wells.
- Established **FG** values found in reliable sources approved by the Director. These could include journal articles, scientific studies, etc.
- An alternative method approved by the Director.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid.

The value for **D** is the depth of the top perforation of the as-built well.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director, but may result in a final MAIP that does not include adjustment for friction loss.

The MAIP can also be adjusted for friction loss if the friction loss can be adequately demonstrated. To account for friction loss, the **MAIP** is equal to **FP** adjusted for friction loss, or:

$$\mathbf{MAIP} = \mathbf{FP} + \text{friction loss (if applicable)}$$

An acceptable method to determine friction loss is to measure it directly. Friction can be calculated when surface and bottom-hole pressures are known. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** are necessary to calculate friction loss.

During the operational life of the well, the depth to the top perforation, fracture gradient, and specific gravity may change. When well workover records, tests or monitoring reports indicate one of the variables in the FP equation has changed, the MAIP calculation will be reviewed. EPA is incorporating the MAIP equations into this Permit instead of identifying a specific MAIP value because it will result in a more efficient application of the true MAIP, as these changes occur over the life of the well to provide greater protection for nearby USDWs.

When additional perforations to the injection zone are added, the Permittee must provide the appropriate workover records and also demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for perforation. It may be necessary to run a step rate test to provide representative data, such as when a new formation (within the approved injection zone) or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

When the fracture gradient or depth to top perforation changes, the formation fracture pressure will be recalculated. The Permittee will also submit fluid analysis that reports SG annually. In the above, a factor of 0.05 has been added to the SG. This adjustment factor allows for the MAIP to be recalculated only if the newly submitted SG is greater than 0.05 from the previous year's SG, without exceeding the fracture pressure of the formation. A MAIP due to the SG change will only be recalculated if the absolute difference of the newly submitted SG and that of the previous year is greater than 0.05.

The new permitted MAIP will become effective when the Director has provided written notification. The Permittee may also request a change to the MAIP by submitting the necessary documentation to support a recalculation of the MAIP.

As discussed above, the formation fracture pressure calculation sets the MAIP to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs. However, it may be that the condition of the well may also limit the permitted MAIP. When external (Part II) MIT demonstrations (such as a temperature survey or radioactive tracer test) are required, the tests required to make this demonstration must be conducted at the permitted MAIP based on the calculations described above. If during testing, the Permittee is unable to achieve the pressure at the permitted MAIP, the new permitted MAIP will be set at the highest pressure achieved during a successful external (Part II) MIT and not the calculated MAIP.

The current permitted MAIP is found in APPENDIX C. Historical permit files for the Tribal C-13 well indicate that the April 3, 2009 step rate was not considered valid. As a result, the authorized MAIP for the Tribal C-13 well was set at 0 psi in the February 2, 2010 authorization to inject letter. However, the MAIP may be revised using the above equation if a valid step rate test is run in the future.

TABLE 5.1 provides an estimated formation fracture pressure based on the information submitted with the application.

TABLE 5.1
Injection Zone Fracture Pressure

Fracture Gradient	Specific Gravity*	Depth (ft)	Friction Loss (psi)	Calculated MAIP (psi)	Authorized MAIP (psi)
N/A	1.054 [1.004 + 0.05]	6,654	N/A	N/A	0[1]

**From the MAIP equation in Part II, Section B.4(b), SG+0.05 or 1.050. SG of 1.004 from 2019 annual injectate fluid sample.*

[1] Historical permit files for the Tribal C-13 well indicate that the April 3, 2009 step-rate was not

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considered valid. As a result, the authorized MAIP for the Tribal C-13 well was set at 0 psi in the February 2, 2010 authorization to inject letter.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year the Permittee must analyze a sample of the injected fluid for parameters specified in APPENDIX D of the Permit. This analysis must be reported to EPA annually as part of the Annual Report to the Director. Any time a new source is added, a fluid analysis must be provided of the injection fluid that includes the new source as discussed above, in PART V Injection Fluid Limitation.

Instantaneous injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures must be observed on a weekly basis. A recording, at least monthly, must be made of that month's injected volume and cumulative fluid volume to date, the maximum and average value for injection tubing pressure and rate, maximum and minimum annulus and bradenhead pressures. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR § 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well must be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable federal, state or local law or regulation. Tubing, packer and other downhole apparatus must be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement must be verified by tagging. A minimum 50 ft surface plug must be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface.

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-19) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in APPENDIX E of the Permit.

PART VIII. Financial Responsibility (40 CFR § 144.52(a)(7))

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,
(b) a letter of credit with a standby trust agreement,
(c) a fully funded trust agreement, OR
(d) a financial test and corporate guarantee.

The Director may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. The Permittee, may also upon written request provide an alternative demonstration of financial responsibility.

If a financial test is provided, evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Other Federal Law (40 CFR § 144.4)

EPA will ensure that issuance of this Permit will be in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act, the Endangered Species Act, and Executive Order 12989 (Environmental Justice), before a final permit decision is made.

National Historic Preservation Act (NHPA)
Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. EPA has determined that a decision to issue a Class II injection well permit for authorization of injection into the Tribal C-13 well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800.

The Tribal C-13 well was drilled in 1951 and currently exists as a permitted injection well within the Steamboat Butte Field. This Permit will authorize the conversion of the Tribal C-13 well from a Class II EOR injection well to a Class II SWD injection well. No new surface-disturbing activity is required for such a conversion of an existing injection well, nor is any such new surface-disturbing activity authorized by this Permit. Authorization from the U.S. BLM would be required for any future activities involving surface disturbance at the location of the Tribal C-13 well.

Based on this information, EPA is proposing to find that no historic properties will be affected as a result of issuing this UIC Permit.

Endangered Species Act (ESA)
Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. EPA has determined that a decision to issue a UIC permit to convert the existing Tribal C-13 well from a Class II EOR to a Class II SWD injection well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402).

The Tribal C-13 well was drilled in 1951 and currently exists as a permitted injection well within the Steamboat Butte Field. This Permit will authorize the conversion of the Tribal C-13 well from a Class II EOR injection well to a Class II SWD injection well. This conversion will result in a change of the purpose of the injection well and the types of fluids that the well can accept for injection. No new surface-disturbing activity is required for such a conversion of an existing injection well, nor is any such new surface-disturbing activity authorized by this Permit. Authorization from the U.S. BLM would be required for any future activities involving surface disturbance at the location of the Tribal C-13 well. In addition, the Tribal C-13 well is not located within an area mapped as critical habitat for threatened and endangered species in the United States Fish and Wildlife Service (USFWS) Environmental Conservation Online System (ECOS).

Based on this information and the nature of the proposed conversion, EPA is proposing a no effect finding for the issuance of this UIC Permit.

Executive Order 12898
On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." EPA has concluded that there may be communities with potential for EJ concerns proximate to the Authorized Permit Area. The primary potential human health or environmental effects to these communities associated with injection well operations would be to

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local aquifers that are currently being used or may be used in the future as USDWs. EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. EPA has concluded that the specific conditions of UIC Permit WY21098-07393 will prevent contamination to USDWs, including USDWs which either are or will be used in the future by communities of EJ concern. These USDWs could include the aquifer within the proposed injection zone. However, in this case portions of the Phosphoria and Tensleep Formations located within the Steamboat Butte Field were exempted on November 25, 1988, upon the effective date of the UIC Program administered by EPA for the Wind River Indian Reservation. The areal extent of the existing aquifer exemption is described in 40 CFR 147.2554. The UIC program will be conducting enhanced public outreach to communities with potential for EJ concerns by publishing a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high.

Public Notice: Merit Energy Company, Tribal C-13 Permit Modification, Wind River Indian Reservation, Wyoming, Permit No. WY21098-07393

How to Comment

Comments accepted through: 09/03/2021

You may comment on the proposed action using email or phone. **Due to office closures related to the COVID-19 outbreak, at this time please do not submit comments via regular mail.**

Submit comments to:

Chris Brown

Brown.Christopher.T@epa.gov

(800) 227-8917, extension 312-6669 or (303) 312-6669

Summary

Project Background Information: Merit Energy Company has submitted an application to convert the existing Tribal C-13 well from a Class II Enhanced Oil Recovery (EOR) well to a Class II Salt Water Disposal (SWD) well. The existing UIC permit (WY21098-07393) became effective on December 24, 2008, and authorization to inject was granted on February 2, 2010. The existing UIC permit allows injection of Class II fluids into the Tensleep and Phosphoria Formations for the purpose of enhanced recovery of oil or natural gas. The conversion to a Class II SWD well would allow for the injection of Class II fluids for the purpose of disposal into the same formations. As defined in 40 Code of Federal Regulations § 146.5, a Class II well injects fluids:

1. Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection;

2. For enhanced recovery of oil or natural gas; and

3. For storage of hydrocarbons which are liquid at standard temperature and pressure.

Proposed Action: EPA proposes issuance of a permit modification of the existing UIC Permit WY21098-07393 for the Tribal C-13 well from a Class II Enhanced Oil Recovery Well Permit to a Class II Salt Water Disposal well Permit.

Notification of any extension of the public comment period will appear at this web address. Alternatively, the public may contact Chris Brown by email at Brown.Christopher.T@epa.gov, or by phone at (800)227-8917, extension 312-6669 or (303) 312-6669, to obtain information about these proposed actions or to be added to the notification list for any extension of the public comment period and any final EPA decision. Due to the current COVID -19 pandemic e-mail correspondence is preferred.

Applicant or Respondent

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

Permit #: WY21098-07393

Public Notice Announcement for EPA UIC Permit Action

The U.S. Environmental Protection Agency intends to issue an Underground Injection Control (UIC) permit modification, under the authority of the Safe Drinking Water Act and UIC program regulations, for the Tribal C-13 well. The Tribal C-13 well is located within Section 30 of Township 4 North and Range 1 West of the Steamboat Butte Field and within the exterior boundaries of the Wind River Indian Reservation. This action would modify the existing UIC Permit WY21098-07393 for the Tribal C-13 well from a Class II Enhanced Oil Recovery Well Permit to a Class II Salt Water Disposal Well Permit. The public notice, which requests comments on this action within 30 days, can be found at EPA Region 8 UIC program's website: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy. Notification of any extension of the public comment period will appear at the web address only and will not appear in this newspaper. Alternatively, the public may contact or call Chris Brown at brown.christopher.t@epa.gov or (303)312-6669 to get a copy of the public notice and/or documentation associated with this section.

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